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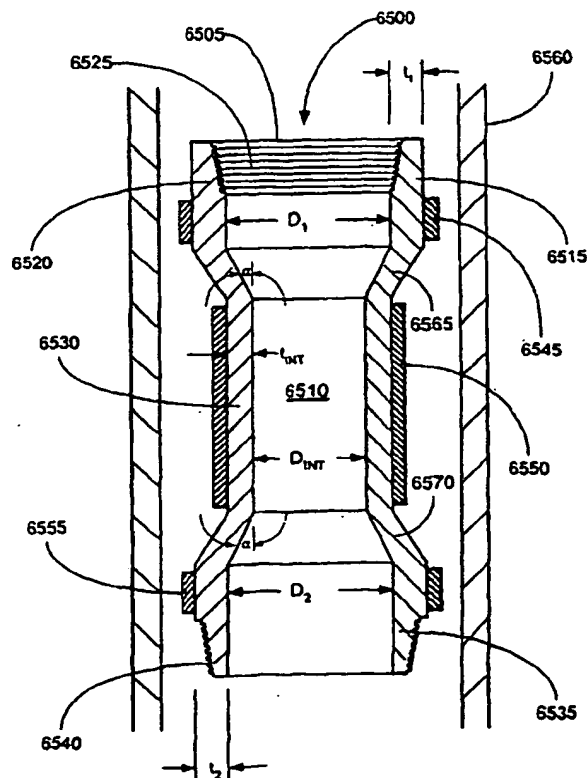
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(54) Title: **TWO-STEP RADIAL EXPANSION**



(57) Abstract: A two-step radial expansion process. A first tubular member (6530) is radially expanded into contact with the interior surface of a second tubular member (6550). Both tubular members are then radially expanded.

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TWO-STEP RADIAL EXPANSION

Background of the Invention

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are
5 installed in the borehole to prevent collapse of the borehole wall and to prevent
undesired outflow of drilling fluid into the formation or inflow of fluid from the
formation into the borehole. The borehole is drilled in intervals whereby a casing
which is to be installed in a lower borehole interval is lowered through a previously
installed casing of an upper borehole interval. As a consequence of this procedure
10 the casing of the lower interval is of smaller diameter than the casing of the upper
interval. Thus, the casings are in a nested arrangement with casing diameters
decreasing in downward direction. Cement annuli are provided between the outer
surfaces of the casings and the borehole wall to seal the casings from the borehole
wall. As a consequence of this nested arrangement a relatively large borehole
15 diameter is required at the upper part of the wellbore. Such a large borehole
diameter involves increased costs due to heavy casing handling equipment, large
drill bits and increased volumes of drilling fluid and drill cuttings. Moreover,
increased drilling rig time is involved due to required cement pumping, cement
hardening, required equipment changes due to large variations in hole diameters
20 drilled in the course of the well, and the large volume of cuttings drilled and
removed.

Conventionally, at the surface end of the wellbore, a wellhead is formed that
typically includes a surface casing, a number of production and/or drilling spools,
valving, and a Christmas tree. Typically the wellhead further includes a concentric
25 arrangement of casings including a production casing and one or more
intermediate casings. The casings are typically supported using load bearing slips
positioned above the ground. The conventional design and construction of
wellheads is expensive and complex.

Conventionally, a wellbore casing cannot be formed during the drilling of
30 a wellbore. Typically, the wellbore is drilled and then a wellbore casing is formed
in the newly drilled section of the wellbore. This delays the completion of a well.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming wellbores and wellheads.

Summary of the Invention

According to one aspect of the present invention, a method of forming a wellbore casing is provided that includes installing a tubular liner and a mandrel in the borehole, injecting fluidic material into the borehole, and radially expanding the liner in the borehole by extruding the liner off of the mandrel.

According to another aspect of the present invention, a method of forming a wellbore casing is provided that includes drilling out a new section of the borehole adjacent to the already existing casing. A tubular liner and a mandrel are then placed into the new section of the borehole with the tubular liner overlapping an already existing casing. A hardenable fluidic sealing material is injected into an annular region between the tubular liner and the new section of the borehole. The annular region between the tubular liner and the new section of the borehole is then fluidically isolated from an interior region of the tubular liner below the mandrel. A non hardenable fluidic material is then injected into the interior region of the tubular liner below the mandrel. The tubular liner is extruded off of the mandrel. The overlap between the tubular liner and the already existing casing is sealed. The tubular liner is supported by overlap with the already existing casing. The mandrel is removed from the borehole. The integrity of the seal of the overlap between the tubular liner and the already existing casing is tested. At least a portion of the second quantity of the hardenable fluidic sealing material is removed from the interior of the tubular liner. The remaining portions of the fluidic hardenable fluidic sealing material are cured. At least a portion of cured fluidic hardenable sealing material within the tubular liner is removed.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member, a mandrel, a tubular member, and a shoe. The support member includes a first fluid passage. The mandrel is coupled to the support member and includes a second fluid passage. The tubular member is coupled to the mandrel. The shoe is coupled to the tubular liner and includes a third fluid passage. The first, second and third fluid passages are operably coupled.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member, an expandable mandrel, a tubular member, a shoe, and at least one sealing member. The support member includes a first fluid passage, a second fluid passage, and a flow control valve coupled to the first and second fluid passages. The expandable mandrel is coupled to the support member and includes a third fluid passage. The tubular member is coupled to the mandrel and includes one or more sealing elements. The shoe is coupled to the tubular member and includes a fourth fluid passage. The at least one sealing member is adapted to prevent the entry of foreign material into an interior region of the tubular member.

According to another aspect of the present invention, a method of joining a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, is provided that includes positioning a mandrel within an interior region of the second tubular member. A portion of an interior region of the second tubular member is pressurized and the second tubular member is extruded off of the mandrel into engagement with the first tubular member.

According to another aspect of the present invention, a tubular liner is provided that includes an annular member having one or more sealing members at an end portion of the annular member, and one or more pressure relief passages at an end portion of the annular member.

According to another aspect of the present invention, a wellbore casing is provided that includes a tubular liner and an annular body of a cured fluidic sealing material. The tubular liner is formed by the process of extruding the tubular liner off of a mandrel.

According to another aspect of the present invention, a tie-back liner for lining an existing wellbore casing is provided that includes a tubular liner and an annular body of cured fluidic sealing material. The tubular liner is formed by the process of extruding the tubular liner off of a mandrel. The annular body of a cured fluidic sealing material is coupled to the tubular liner.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member, a

mandrel, a tubular member and a shoe. The support member includes a first fluid passage. The mandrel is coupled to the support member. The mandrel includes a second fluid passage operably coupled to the first fluid passage, an interior portion, and an exterior portion. The interior portion of the mandrel is drillable.

5 The tubular member is coupled to the mandrel. The shoe is coupled to the tubular member. The shoe includes a third fluid passage operably coupled to the second fluid passage, an interior portion, and an exterior portion. The interior portion of the shoe is drillable.

According to another aspect of the present invention, a wellhead is provided

10 that includes an outer casing and a plurality of concentric inner casings coupled to the outer casing. Each inner casing is supported by contact pressure between an outer surface of the inner casing and an inner surface of the outer casing.

According to another aspect of the present invention, a wellhead is provided that include an outer casing at least partially positioned within a wellbore and a

15 plurality of substantially concentric inner casings coupled to the interior surface of the outer casing. One or more of the inner casings are coupled to the outer casing by expanding one or more of the inner casings into contact with at least a portion of the interior surface of the outer casing.

According to another aspect of the present invention, a method of forming

20 a wellhead is provided that includes drilling a wellbore. An outer casing is positioned at least partially within an upper portion of the wellbore. A first tubular member is positioned within the outer casing. At least a portion of the first tubular member is expanded into contact with an interior surface of the outer casing. A second tubular member is positioned within the outer casing and the

25 first tubular member. At least a portion of the second tubular member is expanded into contact with an interior portion of the outer casing.

According to another aspect of the present invention, an apparatus is provided that includes an outer tubular member, and a plurality of substantially concentric and overlapping inner tubular members coupled to the outer tubular

30 member. Each inner tubular member is supported by contact pressure between an outer surface of the inner casing and an inner surface of the outer inner tubular member.

According to another aspect of the present invention, an apparatus is provided that includes an outer tubular member, and a plurality of substantially concentric inner tubular members coupled to the interior surface of the outer tubular member by the process of expanding one or more of the inner tubular members into contact with at least a portion of the interior surface of the outer tubular member.

According to another aspect of the present invention, a wellbore casing is provided that includes a first tubular member, and a second tubular member coupled to the first tubular member in an overlapping relationship. The inner diameter of the first tubular member is substantially equal to the inner diameter of the second tubular member.

According to another aspect of the present invention, a wellbore casing is provided that includes a tubular member including at least one thin wall section and a thick wall section, and a compressible annular member coupled to each thin wall section.

According to another aspect of the present invention, a method of creating a casing in a borehole located in a subterranean formation is provided that includes supporting a tubular liner and a mandrel in the borehole using a support member. A fluidic material is injected into the borehole. An interior region of the mandrel is pressurized. A portion of the mandrel is displaced relative to the support member. The tubular liner is expanded.

According to another aspect of the present invention, a wellbore casing is provided that includes a first tubular member having a first inside diameter, and a second tubular member having a second inside diameter substantially equal to the first inside diameter coupled to the first tubular member in an overlapping relationship. The first and second tubular members are coupled by the process of deforming a portion of the second tubular member into contact with a portion of the first tubular member.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member including a fluid passage, a mandrel movably coupled to the support member including an expansion cone, at least one pressure chamber defined by and positioned between

the support member and mandrel fluidically coupled to the first fluid passage, and one or more releasable supports coupled to the support member adapted to support the tubular member.

According to another aspect of the present invention, an apparatus is
5 provided that includes one or more solid tubular members, each solid tubular member including one or more external seals, one or more slotted tubular members coupled to the solid tubular members, and a shoe coupled to one of the slotted tubular members.

According to another aspect of the present invention, a method of joining
10 a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member is provided that includes positioning a mandrel within an interior region of the second tubular member. A portion of the interior region of the mandrel is pressurized. The mandrel is displaced relative to the second tubular member. At
15 least a portion of the second tubular member is extruded off of the mandrel into engagement with the first tubular member.

According to another aspect of the present invention, an apparatus is provided that includes one or more primary solid tubulars, each primary solid tubular including one or more external annular seals, n slotted tubulars coupled
20 to the primary solid tubulars, n-1 intermediate solid tubulars coupled to and interleaved among the slotted tubulars, each intermediate solid tubular including one or more external annular seals, and a shoe coupled to one of the slotted tubulars.

According to another aspect of the present invention, a method of isolating
25 a first subterranean zone from a second subterranean zone in a wellbore is provided that includes positioning one or more primary solid tubulars within the wellbore, the primary solid tubulars traversing the first subterranean zone. One or more slotted tubulars are also positioned within the wellbore, the slotted tubulars traversing the second subterranean zone. The slotted tubulars and the
30 solid tubulars are fluidically coupled. The passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid and slotted tubulars is prevented.

According to another aspect of the present invention, a method of extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, is provided that includes positioning one or more primary solid tubulars within the wellbore. The primary solid tubulars with the casing are fluidicly coupled. One or more slotted tubulars are positioned within the wellbore, the slotted tubulars traversing the producing subterranean zone. The slotted tubulars are fluidicly coupled with the solid tubulars. The producing subterranean zone is fluidicly isolated from at least one other subterranean zone within the wellbore. At least one of the slotted tubulars is fluidicly isolated from the producing subterranean zone.

According to another aspect of the present invention, a method of creating a casing in a borehole while also drilling the borehole is also provided that includes installing a tubular liner, a mandrel, and a drilling assembly in the borehole. A fluidic material is injected within the tubular liner, mandrel and drilling assembly. At least a portion of the tubular liner is radially expanded while the borehole is drilled using the drilling assembly. In a preferred embodiment, the injecting includes injecting the fluidic material within an expandable chamber.

According to another aspect of the present invention, an apparatus is also provided that includes a support member, the support member including a first fluid passage; a mandrel coupled to the support member, the mandrel including: a second fluid passage; a tubular member coupled to the mandrel; and a shoe coupled to the tubular liner, the shoe including a third fluid passage; and a drilling assembly coupled to the shoe; wherein the first, second and third fluid passages and the drilling assembly are operably coupled.

According to another aspect of the present invention, a method of forming an underground pipeline within an underground tunnel including at least a first tubular member and a second tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, is also provided that includes positioning the first tubular member within the tunnel; positioning the second tubular member within the tunnel in an overlapping relationship with the first tubular member; positioning a mandrel and a drilling assembly within an interior region of the second tubular member;

injecting a fluidic material within the mandrel, drilling assembly and the second tubular member; extruding at least a portion of the second tubular member off of the mandrel into engagement with the first tubular member; and drilling the tunnel.

5 According to another aspect of the present invention, an apparatus is also provided that includes a wellbore, the wellbore formed by the process of drilling the wellbore; and a tubular liner positioned within the wellbore, the tubular liner formed by the process of extruding the tubular liner off of a mandrel while drilling the wellbore. In a preferred embodiment, the tubular liner is formed by the
10 process of: placing the tubular liner and mandrel within the wellbore; and pressurizing an interior portion of the tubular liner.

 According to another aspect of the present invention, a method of forming a wellbore casing in a wellbore is also provided that includes drilling out the wellbore while forming the wellbore casing.

15 According to another aspect of the present invention, a method of expanding a tubular member is provided that includes placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member.

 According to another aspect of the present invention, a method of coupling
20 a tubular member to preexisting structure is provided that includes positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member.

25 According to another aspect of the present invention, a method of repairing a defect in a preexisting structure using a tubular member is provided that includes positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the
30 mandrel with respect to the tubular member.

 According to another aspect of the present invention, an apparatus for radially expanding a tubular member is provided that includes a first tubular

member, a second tubular member positioned within the first tubular member, a third tubular member movably coupled to and positioned within the second tubular member, a first annular sealing member for sealing an interface between the first and second tubular members, a second annular sealing member for sealing
5 an interface between the second and third tubular members, and a mandrel positioned within the first tubular member and coupled to an end of the third tubular member.

According to another aspect of the present invention, an apparatus is provided that includes a tubular member, a piston adapted to expand the diameter
10 of the tubular member positioned within the tubular member, and an annular chamber defined by the piston and tubular member. The piston includes a passage for conveying fluids out of the tubular member.

According to another aspect of the present invention, a wellbore casing is provided that includes a first tubular member and a second tubular member
15 coupled to the first tubular member. The second tubular member is coupled to the first tubular member by the process of: positioning the second tubular member in an overlapping relationship to the first tubular member, placing a mandrel within the second tubular member, pressurizing an annular region within the second tubular member, and displacing the mandrel with respect to the second tubular
20 member.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure and a tubular member coupled to the preexisting structure. The tubular member is coupled to the preexisting structure by the process of: positioning the tubular member in an overlapping
25 relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure having a defective portion and a
30 tubular member coupled to the defective portion of the preexisting structure. The tubular member is coupled to the defective portion of the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to

the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, a method of expanding
5 a tubular member is provided that includes placing a mandrel within the tubular member, pressurizing a region within the tubular member; and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, a method of coupling
a tubular member to preexisting structure has been provided that includes
10 positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, a method of repairing
15 a defect in a preexisting structure using a tubular member is provided that includes positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, an apparatus for
20 radially expanding a tubular member is provided that includes a first tubular member, a second tubular member coupled to the first tubular member, a third tubular member coupled to the second tubular member, and a mandrel positioned within the second tubular member and coupled to an end portion of the third
25 tubular member.

According to another aspect of the present invention, an apparatus is provided that includes a tubular member, a piston adapted to expand the diameter of the tubular member positioned within the tubular member, the piston including a passage for conveying fluids out of the tubular member.

According to another aspect of the present invention, a wellbore casing is
30 provided that includes a first tubular member and a second tubular member coupled to the first tubular member. The second tubular member is coupled to the

first tubular member by the process of: positioning the second tubular member in an overlapping relationship to the first tubular member, placing a mandrel within the second tubular member, pressurizing an interior region within the second tubular member, and displacing the mandrel with respect to the second tubular
5 member.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure and a tubular member coupled to the preexisting structure. The tubular member is coupled to the preexisting structure by the process of: positioning the tubular member in an overlapping
10 relationship to the preexisting structure; placing a mandrel within the tubular member; pressurizing an interior region within the tubular member; and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure having a defective portion and a
15 tubular member coupled to the defective portion of the preexisting structure. The tubular member is coupled to the defective portion of the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and
20 displacing the mandrel with respect to the tubular member.

According to another aspect of the invention, an apparatus is provided that includes a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more sealing members for sealing the
25 interface between the first and second tubular members.

According to another aspect of the present invention, an apparatus is provided that includes a tubular assembly having a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more
30 sealing members for sealing the interface between the first and second tubular members. The tubular assembly is formed by the process of radially expanding the tubular assembly.

According to another aspect of the present invention, an apparatus is provided that includes a tubular member and a mandrel positioned within the tubular member that includes a conical surface have an angle of attack ranging from about 10 to 30 degrees.

5 According to another aspect of the present invention, an expansion cone for expanding a tubular member is provided that includes a housing including a tapered first end and a second end, one or more grooves formed in the outer surface of the tapered first end, and one or more axial flow passages fluidically coupled to the circumferential grooves.

10 According to another aspect of the present invention, a method of lubricating the interface between a tubular member and an expansion cone having a first tapered end and a second end during the radial expansion of the tubular member by the expansion cone, wherein the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and
15 a trailing edge portion, is provided that includes injecting a lubricating fluid into the trailing edge portion.

 According to another aspect of the present invention, a method of removing debris formed during the radial expansion of a tubular member by an expansion cone from the interface between the tubular member and the expansion cone, the
20 expansion cone including a first tapered end and a second end, the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and a trailing edge portion, is provided that includes injecting a lubricating fluid into the interface between the tubular member and the expansion cone.

25 According to another aspect of the present invention, a tubular member is provided that includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member
30 for radial expansions of up to about 25%.

 According to another aspect of the present invention, a wellbore casing is provided that includes one or more tubular members. Each tubular member

includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of
5 up to about 25%.

According to another aspect of the present invention, a method of forming a wellbore casing is provided that includes placing a tubular member and an expansion cone in a wellbore and displacing the expansion cone relative to the tubular member. The tubular member includes an annular member having a wall
10 thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

According to another aspect of the present invention, a method of selecting
15 a group of tubular members for subsequent radial expansion is provided that includes radially expanding the ends of a representative sample of the group of tubular members, measuring the amount of necking of the walls of the radially expanded ends of the tubular members, and if the radially expanded ends of the tubular members do not exhibit necking for radial expansions of up to about 25%,
20 then accepting the group of tubular members.

According to another aspect of the present invention, a method of selecting a group of tubular members is provided that includes radially expanding the ends of a representative sample of the group of tubular members until each of the tubular members fail, and if the radially expanded ends of the tubular members
25 do not fail for radial expansions of up to about 30%, then accepting the group of tubular members.

According to another aspect of the present invention, a method of inserting a tubular member into a wellbore is provided that includes injecting a lubricating fluid into the wellbore and inserting the tubular member into the wellbore.

30 According to another aspect of the present invention, an expandable tubular member is provided that includes a first tubular section having a first outer diameter, an intermediate tubular section coupled to the first tubular section

having an intermediate outer diameter, and a second tubular section having a second outer diameter coupled to the intermediate tubular section having a second outer diameter. The first and second outer diameters are greater than the intermediate outer diameter.

- 5 According to another aspect of the present invention, a method of fabricating an expandable tubular member is provided that includes providing a tubular member having a first end, a second end, and an intermediate portion and radially expanding the first end and the second end of the tubular member.

- 10 According to another aspect of the present invention, an expansion cone for radially expanding a tubular member is provided that includes a first outer surface having a first angle of attack and a second outer surface coupled to the first outer surface having a second angle of attack. The first angle of attack is greater than the second angle of attack.

- 15 According to another aspect of the present invention, an apparatus is provided that includes a tubular member formed by the process of radially expanding an unexpanded tubular member into contact with an approximately cylindrical passage using an expansion cone. The unexpanded tubular member includes a first tubular section having a first outer diameter, an intermediate tubular section coupled to the first tubular section having an intermediate outer
20 diameter and a second tubular section having a second outer diameter coupled to the intermediate tubular section having a second outer diameter. The first and second outer diameters are greater than the intermediate outer diameter.

- 25 According to another aspect of the present invention, a method of joining a first tubular member to a second tubular member is provided that includes positioning at least a portion of the second tubular member within the first tubular member, radially expanding at least a portion of the second tubular member into contact with the first tubular member, and radially expanding the first and second tubular members. The interior diameter of the radially expanded second tubular member is substantially equal to the interior diameter of the radially unexpanded
30 portion of the first tubular member.

Brief Description of the Drawings

FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for creating a casing within the new section of the well borehole.

FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a first quantity of a fluidic material into the new section of the well borehole.

FIG. 3a is another fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a second quantity of a fluidic material into the new section of the well borehole.

FIG. 5 is a fragmentary cross-sectional view illustrating the drilling out of a portion of the cured hardenable fluidic sealing material from the new section of the well borehole.

FIG. 6 is a cross-sectional view of an embodiment of the overlapping joint between adjacent tubular members.

FIG. 7 is a fragmentary cross-sectional view of a preferred embodiment of the apparatus for creating a casing within a well borehole.

FIG. 8 is a fragmentary cross-sectional illustration of the placement of an expanded tubular member within another tubular member.

FIG. 9 is a cross-sectional illustration of a preferred embodiment of an apparatus for forming a casing including a drillable mandrel and shoe.

FIG. 9a is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9b is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9c is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 10a is a cross-sectional illustration of a wellbore including a pair of adjacent overlapping casings.

FIG. 10b is a cross-sectional illustration of an apparatus and method for creating a tie-back liner using an expandable tubular member.

FIG. 10c is a cross-sectional illustration of the pumping of a fluidic sealing material into the annular region between the tubular member and the existing casing.

FIG. 10d is a cross-sectional illustration of the pressurizing of the interior
5 of the tubular member below the mandrel.

FIG. 10e is a cross-sectional illustration of the extrusion of the tubular member off of the mandrel.

FIG. 10f is a cross-sectional illustration of the tie-back liner before drilling out the shoe and packer.

10 FIG. 10g is a cross-sectional illustration of the completed tie-back liner created using an expandable tubular member.

FIG. 11a is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 11b is a fragmentary cross-sectional view illustrating the placement of
15 an embodiment of an apparatus for hanging a tubular liner within the new section of the well borehole.

FIG. 11c is a fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

20 FIG. 11d is a fragmentary cross-sectional view illustrating the introduction of a wiper dart into the new section of the well borehole.

FIG. 11e is a fragmentary cross-sectional view illustrating the injection of a second quantity of a hardenable fluidic sealing material into the new section of the well borehole.

25 FIG. 11f is a fragmentary cross-sectional view illustrating the completion of the tubular liner.

FIG. 12 is a cross-sectional illustration of a preferred embodiment of a wellhead system utilizing expandable tubular members.

FIG. 13 is a partial cross-sectional illustration of a preferred embodiment
30 of the wellhead system of FIG. 12.

FIG. 14a is an illustration of the formation of an embodiment of a mono-diameter wellbore casing.

FIG. 14b is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14c is another illustration of the formation of the mono-diameter wellbore casing.

5 FIG. 14d is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14e is another illustration of the formation of the mono-diameter wellbore casing.

10 FIG. 14f is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 15 is an illustration of an embodiment of an apparatus for expanding a tubular member.

FIG. 15a is another illustration of the apparatus of FIG. 15.

FIG. 15b is another illustration of the apparatus of FIG. 15.

15 FIG. 16 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 17 is an illustration of an embodiment of an apparatus for expanding a tubular member.

FIG. 17a is another illustration of the apparatus of FIG. 16.

20 FIG. 17b is another illustration of the apparatus of FIG. 16.

FIG. 18 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 19 is an illustration of another embodiment of an apparatus for expanding a tubular member.

25 FIG. 19a is another illustration of the apparatus of FIG. 17.

FIG. 19b is another illustration of the apparatus of FIG. 17.

FIG. 20 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

30 FIG. 21 is an illustration of the isolation of subterranean zones using expandable tubulars.

FIG. 22a is a fragmentary cross-sectional illustration of an embodiment of an apparatus for forming a wellbore casing while drilling a wellbore.

FIG. 22b is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

FIG. 22c is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

5 FIG. 22d is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

FIG. 23a is a fragmentary cross-section illustration of an embodiment of an apparatus and method for expanding tubular members.

10 FIG. 23b is another fragmentary cross-sectional illustration of the apparatus of FIG. 23a.

FIG. 23c is another fragmentary cross-sectional illustration of the apparatus of FIG. 23a.

FIG. 24a is a fragmentary cross-section illustration of an embodiment of an apparatus and method for expanding tubular members.

15 FIG. 24b is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

FIG. 24c is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

20 FIG. 24d is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

FIG. 24e is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

FIG. 25 is a partial cross-sectional illustration of an expansion mandrel expanding a tubular member.

25 FIG. 26 is a graphical illustration of the relationship between propagation pressure and the angle of attack of the expansion mandrel.

FIG. 27 is a cross-sectional illustration of an embodiment of an expandable connector.

30 FIG. 28 is a cross-sectional illustration of another embodiment of an expandable connector.

FIG. 29 is a cross-sectional illustration of another embodiment of an expandable connector.

FIG. 30 is a cross-sectional illustration of another embodiment of an expandable connector.

FIG. 31 is a fragmentary cross-sectional illustration of the lubrication of the interface between an expansion mandrel and a tubular member during the radial
5 expansion process.

FIG. 32 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 33 is an illustration of an embodiment of an expansion mandrel
10 including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 34 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 35 is an illustration of an embodiment of an expansion mandrel
15 including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 36 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel
20 and a tubular member during the radial expansion of the tubular member.

FIG. 37 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 38 is an illustration of an embodiment of an expansion mandrel
25 including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 39 is an illustration of a preferred embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular
30 member.

FIG. 40 is a cross-sectional illustration of the first axial groove of the expansion mandrel of FIG. 39.

FIG. 41 is a cross-sectional illustration of the circumferential groove of the expansion mandrel of FIG. 39.

FIG. 42 is a cross-sectional illustration of one of the second axial grooves of the expansion mandrel of FIG. 39.

5 FIG. 43 is a cross sectional illustration of an embodiment of an expansion mandrel including internal flow passages having inserts for adjusting the flow of lubricant fluids.

FIG. 44 is a cross sectional illustration of the expansion mandrel of FIG. 43 further including an insert having a filter for filtering out foreign materials from
10 the lubricant fluids.

FIG. 45 is a cross sectional illustration of a preferred embodiment of an expandible tubular for use in forming and/or repairing a wellbore casing, pipeline, or foundation support.

FIG. 46 is a cross sectional illustration of the flared end of a tubular member
15 selected for testing.

FIG. 47 is a cross sectional illustration of the flared end of a tubular member selected for testing that has structurally failed.

FIG. 48 is a cross sectional illustration of an embodiment of an expandable tubular member.

20 FIG. 49 is a flow chart illustration of an embodiment of a method for fabricating the expandable tubular member of FIG. 48.

FIG. 50a is a cross sectional illustration of a tubular member having upset end portions.

FIG. 50b is a cross sectional illustration of the tubular member of FIG. 50a
25 after radial expansion of the upset end portions.

FIG. 50c is a cross sectional illustration of the tubular member of FIG. 50b further including expandable threaded connections provided in the expanded upset end portions.

FIG. 50d is a cross sectional illustration of tubular member of FIG. 50c,
30 further including protective members provided on the outside diameter of the upset expanded portions of the tubular member.

FIG. 50e is a cross sectional illustration of the tubular member of FIG. 50d, further including a sealing member provided on the outside diameter of the intermediate unexpanded portion of the tubular member.

FIG. 51 is an illustration of an embodiment of an expansion cone optimally adapted to radially expand the tubular member of FIG. 48.

FIG. 52 is an illustration of another embodiment of an expansion cone optimally adapted to radially expand the tubular member of FIG. 48.

Fig. 53a is a fragmentary cross-sectional illustration of an embodiment of a wellbore casing formed using any one of the methods and apparatus for radially expanding a tubular member illustrated in Figs. 1-52.

Fig. 53b is a fragmentary cross-sectional illustration of an embodiment of a method and apparatus for further radially expanding the wellbore casing of Fig. 53a.

Fig. 53c. is a fragmentary cross-sectional illustration of the wellbore casing of Fig. 53b after further radial expansion.

Detailed Description of the Illustrative Embodiments

An apparatus and method for forming a wellbore casing within a subterranean formation is provided. The apparatus and method permits a wellbore casing to be formed in a subterranean formation by placing a tubular member and a mandrel in a new section of a wellbore, and then extruding the tubular member off of the mandrel by pressurizing an interior portion of the tubular member. The apparatus and method further permits adjacent tubular members in the wellbore to be joined using an overlapping joint that prevents fluid and or gas passage. The apparatus and method further permits a new tubular member to be supported by an existing tubular member by expanding the new tubular member into engagement with the existing tubular member. The apparatus and method further minimizes the reduction in the hole size of the wellbore casing necessitated by the addition of new sections of wellbore casing.

An apparatus and method for forming a tie-back liner using an expandable tubular member is also provided. The apparatus and method permits a tie-back liner to be created by extruding a tubular member off of a mandrel by pressurizing

and interior portion of the tubular member. In this manner, a tie-back liner is produced. The apparatus and method further permits adjacent tubular members in the wellbore to be joined using an overlapping joint that prevents fluid and/or gas passage. The apparatus and method further permits a new tubular member
5 to be supported by an existing tubular member by expanding the new tubular member into engagement with the existing tubular member.

An apparatus and method for expanding a tubular member is also provided that includes an expandable tubular member, mandrel and a shoe. In a preferred embodiment, the interior portions of the apparatus is composed of materials that
10 permit the interior portions to be removed using a conventional drilling apparatus. In this manner, in the event of a malfunction in a downhole region, the apparatus may be easily removed.

An apparatus and method for hanging an expandable tubular liner in a wellbore is also provided. The apparatus and method permit a tubular liner to be
15 attached to an existing section of casing. The apparatus and method further have application to the joining of tubular members in general.

An apparatus and method for forming a wellhead system is also provided. The apparatus and method permit a wellhead to be formed including a number of expandable tubular members positioned in a concentric arrangement. The
20 wellhead preferably includes an outer casing that supports a plurality of concentric casings using contact pressure between the inner casings and the outer casing. The resulting wellhead system eliminates many of the spools conventionally required, reduces the height of the Christmas tree facilitating servicing, lowers the load bearing areas of the wellhead resulting in a more stable system, and
25 eliminates costly and expensive hanger systems.

An apparatus and method for forming a mono-diameter well casing is also provided. The apparatus and method permit the creation of a well casing in a wellbore having a substantially constant internal diameter. In this manner, the operation of an oil or gas well is greatly simplified.

30 An apparatus and method for expanding tubular members is also provided. The apparatus and method utilize a piston-cylinder configuration in which a pressurized chamber is used to drive a mandrel to radially expand tubular

members. In this manner, higher operating pressures can be utilized. Throughout the radial expansion process, the tubular member is never placed in direct contact with the operating pressures. In this manner, damage to the tubular member is prevented while also permitting controlled radial expansion of the tubular member
5 in a wellbore.

An apparatus and method for forming a mono-diameter wellbore casing is also provided. The apparatus and method utilize a piston-cylinder configuration in which a pressurized chamber is used to drive a mandrel to radially expand tubular members. In this manner, higher operating pressures can be utilized.
10 Throughout the radial expansion process, the tubular member is never placed in direct contact with the operating pressures. In this manner, damage to the tubular member is prevented while also permitting controlled radial expansion of the tubular member in a wellbore.

An apparatus and method for isolating one or more subterranean zones
15 from one or more other subterranean zones is also provided. The apparatus and method permits a producing zone to be isolated from a nonproducing zone using a combination of solid and slotted tubulars. In the production mode, the teachings of the present disclosure may be used in combination with conventional, well known, production completion equipment and methods using a series of packers,
20 solid tubing, perforated tubing, and sliding sleeves, which will be inserted into the disclosed apparatus to permit the commingling and/or isolation of the subterranean zones from each other.

An apparatus and method for forming a wellbore casing while the wellbore is drilled is also provided. In this manner, a wellbore casing can be formed
25 simultaneous with the drilling out of a new section of the wellbore. In a preferred embodiment, the apparatus and method is used in combination with one or more of the apparatus and methods disclosed in the present disclosure for forming wellbore casings using expandable tubulars. Alternatively, the method and apparatus can be used to create a pipeline or tunnel in a time efficient manner.

30 An expandable connector is also provided. In a preferred implementation, the expandable connector is used in conjunction with one or more of the disclosed embodiments for expanding tubular members. In this manner, the expansion of

a plurality of tubular members coupled to one another using the expandable connector is optimized.

A lubrication and self-cleaning system for an expansion cone is also provided. In a preferred implementation, the expansion cone includes one or more
5 circumferential grooves and one or more axial grooves for providing a supply of lubricating fluid to the trailing edge portion of the interface between the expansion cone and a tubular member during the radial expansion process. In this manner, the frictional forces created during the radial expansion process are reduced which results in a reduction in the required operating pressures for radially expanding
10 the tubular member. Furthermore, the supply of lubricating fluid preferably removes loose material from tapered end of the expansion cone that is formed during the radial expansion process.

A method of testing and selecting tubular members for radial expansion operations is also provided. In a preferred embodiment, the method provides
15 tubular members that are optimally suited for radial expansion. In this manner, radially expanded tubular members having optimal structural properties are provided.

An expandable tubular member is provided that includes pre-expanded ends. In this manner, the subsequent radial expansion of the expandable tubular
20 member is optimized.

An expansion cone for expanding a tubular member is also provided that include a first outer surface having a first angle of attack and a second outer surface having a second angle of attack less than the first angle of attack. In this manner, the expansion of tubular members is optimally provided.

25 A two-step process for coupling a first tubular member to a second tubular member is also provided. During the first stage of the process, the first tubular member is preferably radially expanded into contact with the interior surface of the second tubular member. During the second stage of the process, both tubular members are radially expanded. The resulting assembly preferably provides a
30 substantially constant inside diameter.

In several alternative embodiments, the apparatus and methods are used to form and/or repair wellbore casings, pipelines, and/or structural supports.

Referring initially to Figs. 1-5, an embodiment of an apparatus and method for forming a wellbore casing within a subterranean formation will now be described. As illustrated in Fig. 1, a wellbore 100 is positioned in a subterranean formation 105. The wellbore 100 includes an existing cased section 110 having a tubular casing 115 and an annular outer layer of cement 120.

In order to extend the wellbore 100 into the subterranean formation 105, a drill string 125 is used in a well known manner to drill out material from the subterranean formation 105 to form a new section 130.

As illustrated in Fig. 2, an apparatus 200 for forming a wellbore casing in a subterranean formation is then positioned in the new section 130 of the wellbore 100. The apparatus 200 preferably includes an expandable mandrel or pig 205, a tubular member 210, a shoe 215, a lower cup seal 220, an upper cup seal 225, a fluid passage 230, a fluid passage 235, a fluid passage 240, seals 245, and a support member 250.

The expandable mandrel 205 is coupled to and supported by the support member 250. The expandable mandrel 205 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 205 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the expandable mandrel 205 comprises a hydraulic expansion tool as disclosed in U.S. Patent No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member 210 is supported by the expandable mandrel 205. The tubular member 210 is expanded in the radial direction and extruded off of the expandable mandrel 205. The tubular member 210 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/casing. In a preferred embodiment, the tubular member 210 is fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 210 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred

embodiment, the inner and outer diameters of the tubular member 210 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member 210 preferably comprises a solid member.

5 In a preferred embodiment, the end portion 260 of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 205 when it completes the extrusion of tubular member 210. In a preferred embodiment, the length of the tubular member 210 is limited to minimize the possibility of buckling. For typical tubular member 210 materials, the length of
10 the tubular member 210 is preferably limited to between about 40 to 20,000 feet in length.

 The shoe 215 is coupled to the expandable mandrel 205 and the tubular member 210. The shoe 215 includes fluid passage 240. The shoe 215 may comprise any number of conventional commercially available shoes such as, for
15 example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 215 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down
20 plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 210 in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally allow the complete drill out of the shoe and
 plug after the completion of the cementing and expansion operations.

25 In a preferred embodiment, the shoe 215 includes one or more through and side outlet ports in fluidic communication with the fluid passage 240. In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region outside the shoe 215 and tubular member 210. In a preferred embodiment, the shoe 215 includes the fluid passage 240 having an inlet geometry that can
30 receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

The lower cup seal 220 is coupled to and supported by the support member 250. The lower cup seal 220 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expandable mandrel 205. The lower cup seal 220 may comprise any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 220 comprises a SIP cup seal, available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign material and contain a body of lubricant.

10 The upper cup seal 225 is coupled to and supported by the support member 250. The upper cup seal 225 prevents foreign materials from entering the interior region of the tubular member 210. The upper cup seal 225 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the upper cup seal 225 comprises a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant.

The fluid passage 230 permits fluidic materials to be transported to and from the interior region of the tubular member 210 below the expandable mandrel 205. The fluid passage 230 is coupled to and positioned within the support member 250 and the expandable mandrel 205. The fluid passage 230 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 205. The fluid passage 230 is preferably positioned along a centerline of the apparatus 200.

25 The fluid passage 230 is preferably selected, in the casing running mode of operation, to transport materials such as drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore which could cause a loss of wellbore fluids and lead to hole collapse.

The fluid passage 235 permits fluidic materials to be released from the fluid passage 230. In this manner, during placement of the apparatus 200 within the

new section 130 of the wellbore 100, fluidic materials 255 forced up the fluid passage 230 can be released into the wellbore 100 above the tubular member 210 thereby minimizing surge pressures on the wellbore section 130. The fluid passage 235 is coupled to and positioned within the support member 250. The fluid
5 passage is further fluidically coupled to the fluid passage 230.

The fluid passage 235 preferably includes a control valve for controllably opening and closing the fluid passage 235. In a preferred embodiment, the control valve is pressure activated in order to controllably minimize surge pressures. The fluid passage 235 is preferably positioned substantially orthogonal to the centerline
10 of the apparatus 200.

The fluid passage 235 is preferably selected to convey fluidic materials at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to reduce the drag on the apparatus 200 during insertion into the new section 130 of the wellbore 100 and to minimize surge pressures on the
15 new wellbore section 130.

The fluid passage 240 permits fluidic materials to be transported to and from the region exterior to the tubular member 210 and shoe 215. The fluid passage 240 is coupled to and positioned within the shoe 215 in fluidic communication with the interior region of the tubular member 210 below the
20 expandable mandrel 205. The fluid passage 240 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in fluid passage 240 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 210 below the expandable mandrel 205 can be fluidically isolated from the region exterior to the tubular member 210. This permits
25 the interior region of the tubular member 210 below the expandable mandrel 205 to be pressurized. The fluid passage 240 is preferably positioned substantially along the centerline of the apparatus 200.

The fluid passage 240 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0
30 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 210 and the new section 130 of the wellbore 100 with fluidic materials. In a preferred embodiment, the fluid passage 240

includes an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

The seals 245 are coupled to and supported by an end portion 260 of the tubular member 210. The seals 245 are further positioned on an outer surface 265 of the end portion 260 of the tubular member 210. The seals 245 permit the overlapping joint between the end portion 270 of the casing 115 and the portion 260 of the tubular member 210 to be fluidically sealed. The seals 245 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 245 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the end 260 of the tubular member 210 and the end 270 of the existing casing 115.

In a preferred embodiment, the seals 245 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 210 from the existing casing 115. In a preferred embodiment, the frictional force optimally provided by the seals 245 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 210.

The support member 250 is coupled to the expandable mandrel 205, tubular member 210, shoe 215, and seals 220 and 225. The support member 250 preferably comprises an annular member having sufficient strength to carry the apparatus 200 into the new section 130 of the wellbore 100. In a preferred embodiment, the support member 250 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 200. In a preferred embodiment, the support member 250 comprises coiled tubing.

In a preferred embodiment, a quantity of lubricant 275 is provided in the annular region above the expandable mandrel 205 within the interior of the tubular member 210. In this manner, the extrusion of the tubular member 210 off of the expandable mandrel 205 is facilitated. The lubricant 275 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze

(3100). In a preferred embodiment, the lubricant 275 comprises Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

5 In a preferred embodiment, the support member 250 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 200. In this manner, the introduction of foreign material into the apparatus 200 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 200.

10 In a preferred embodiment, before or after positioning the apparatus 200 within the new section 130 of the wellbore 100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 100 that might clog up the various flow passages and valves of the apparatus 200 and to ensure that no foreign material interferes with the expansion
15 process.

 As illustrated in Fig. 3, the fluid passage 235 is then closed and a hardenable fluidic sealing material 305 is then pumped from a surface location into the fluid passage 230. The material 305 then passes from the fluid passage 230 into the interior region 310 of the tubular member 210 below the expandable mandrel 205.
20 The material 305 then passes from the interior region 310 into the fluid passage 240. The material 305 then exits the apparatus 200 and fills the annular region 315 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 305 causes the material 305 to fill up at least a portion of the annular region 315.

25 The material 305 is preferably pumped into the annular region 315 at pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being
30 pumped. The optimum flow rate and operating pressure are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material 305 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 305 comprises a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 315. The optimum blend of the blended cement is preferably determined using conventional empirical methods.

The annular region 315 preferably is filled with the material 305 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular region 315 of the new section 130 of the wellbore 100 will be filled with material 305.

In a particularly preferred embodiment, as illustrated in Fig. 3a, the wall thickness and/or the outer diameter of the tubular member 210 is reduced in the region adjacent to the mandrel 205 in order optimally permit placement of the apparatus 200 in positions in the wellbore with tight clearances. Furthermore, in this manner, the initiation of the radial expansion of the tubular member 210 during the extrusion process is optimally facilitated.

As illustrated in Fig. 4, once the annular region 315 has been adequately filled with material 305, a plug 405, or other similar device, is introduced into the fluid passage 240 thereby fluidically isolating the interior region 310 from the annular region 315. In a preferred embodiment, a non-hardenable fluidic material 306 is then pumped into the interior region 310 causing the interior region to pressurize. In this manner, the interior of the expanded tubular member 210 will not contain significant amounts of cured material 305. This reduces and simplifies the cost of the entire process. Alternatively, the material 305 may be used during this phase of the process. Once the interior region 310 becomes sufficiently pressurized, the tubular member 210 is extruded off of the expandable mandrel 205. During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210. In a preferred embodiment,

during the extrusion process, the mandrel 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In an alternative preferred embodiment, the extrusion process is commenced with the tubular member 210
5 positioned above the bottom of the new wellbore section 130, keeping the mandrel 205 stationary, and allowing the tubular member 210 to extrude off of the mandrel 205 and fall down the new wellbore section 130 under the force of gravity.

The plug 405 is preferably placed into the fluid passage 240 by introducing the plug 405 into the fluid passage 230 at a surface location in a conventional
10 manner. The plug 405 preferably acts to fluidically isolate the hardenable fluidic sealing material 305 from the non hardenable fluidic material 306.

The plug 405 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch-
15 down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the plug 405 comprises a MSC latch-down plug available from Halliburton Energy Services in Dallas, TX.

After placement of the plug 405 in the fluid passage 240, a non hardenable fluidic material 306 is preferably pumped into the interior region 310 at pressures
20 and flow rates ranging, for example, from approximately 400 to 10,000 psi and 30 to 4,000 gallons/min. In this manner, the amount of hardenable fluidic sealing material within the interior 310 of the tubular member 210 is minimized. In a preferred embodiment, after placement of the plug 405 in the fluid passage 240, the non hardenable material 306 is preferably pumped into the interior region 310
25 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to maximize the extrusion speed.

In a preferred embodiment, the apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will depend upon the geometry of the expansion
30 mandrel 205, the material composition of the tubular member 210 and expansion mandrel 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the

tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the mandrel 205.

- 5 For typical tubular members 210, the extrusion of the tubular member 210 off of the expandable mandrel will begin when the pressure of the interior region 310 reaches, for example, approximately 500 to 9,000 psi.

10 During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expandable mandrel 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 2 ft/sec in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

- 15 When the end portion 260 of the tubular member 210 is extruded off of the expandable mandrel 205, the outer surface 265 of the end portion 260 of the tubular member 210 will preferably contact the interior surface 410 of the end portion 270 of the casing 115 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50
20 to 20,000 psi. In a preferred embodiment, the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to provide optimum pressure to activate the annular sealing members 245 and optimally provide resistance to axial motion to accommodate typical tensile and compressive loads.

25 The overlapping joint between the section 410 of the existing casing 115 and the section 265 of the expanded tubular member 210 preferably provides a gaseous and fluidic seal. In a particularly preferred embodiment, the sealing members 245 optimally provide a fluidic and gaseous seal in the overlapping joint.

- 30 In a preferred embodiment, the operating pressure and flow rate of the non hardenable fluidic material 306 is controllably ramped down when the expandable mandrel 205 reaches the end portion 260 of the tubular member 210. In this manner, the sudden release of pressure caused by the complete extrusion of the

tubular member 210 off of the expandable mandrel 205 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 205 is within about 5 feet from completion of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 250 in order to absorb the shock caused by the sudden release of pressure. The shock absorber may comprise, for example, any conventional commercially available shock absorber adapted for use in wellbore operations.

Alternatively, or in combination, a mandrel catching structure is provided in the end portion 260 of the tubular member 210 in order to catch or at least decelerate the mandrel 205.

Once the extrusion process is completed, the expandable mandrel 205 is removed from the wellbore 100. In a preferred embodiment, either before or after the removal of the expandable mandrel 205, the integrity of the fluidic seal of the overlapping joint between the upper portion 260 of the tubular member 210 and the lower portion 270 of the casing 115 is tested using conventional methods.

If the fluidic seal of the overlapping joint between the upper portion 260 of the tubular member 210 and the lower portion 270 of the casing 115 is satisfactory, then any uncured portion of the material 305 within the expanded tubular member 210 is then removed in a conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member 210. The mandrel 205 is then pulled out of the wellbore section 130 and a drill bit or mill is used in combination with a conventional drilling assembly 505 to drill out any hardened material 305 within the tubular member 210. The material 305 within the annular region 315 is then allowed to cure.

As illustrated in Fig. 5, preferably any remaining cured material 305 within the interior of the expanded tubular member 210 is then removed in a conventional manner using a conventional drill string 505. The resulting new section of casing 510 includes the expanded tubular member 210 and an outer annular layer 515 of cured material 305. The bottom portion of the apparatus 200

comprising the shoe 215 and dart 405 may then be removed by drilling out the shoe 215 and dart 405 using conventional drilling methods.

In a preferred embodiment, as illustrated in Fig. 6, the upper portion 260 of the tubular member 210 includes one or more sealing members 605 and one or
5 more pressure relief holes 610. In this manner, the overlapping joint between the lower portion 270 of the casing 115 and the upper portion 260 of the tubular member 210 is pressure-tight and the pressure on the interior and exterior surfaces of the tubular member 210 is equalized during the extrusion process.

In a preferred embodiment, the sealing members 605 are seated within
10 recesses 615 formed in the outer surface 265 of the upper portion 260 of the tubular member 210. In an alternative preferred embodiment, the sealing members 605 are bonded or molded onto the outer surface 265 of the upper portion 260 of the tubular member 210. The pressure relief holes 610 are preferably positioned in the last few feet of the tubular member 210. The pressure relief
15 holes reduce the operating pressures required to expand the upper portion 260 of the tubular member 210. This reduction in required operating pressure in turn reduces the velocity of the mandrel 205 upon the completion of the extrusion process. This reduction in velocity in turn minimizes the mechanical shock to the entire apparatus 200 upon the completion of the extrusion process.

20 Referring now to Fig. 7, a particularly preferred embodiment of an apparatus 700 for forming a casing within a wellbore preferably includes an expandable mandrel or pig 705, an expandable mandrel or pig container 710, a tubular member 715, a float shoe 720, a lower cup seal 725, an upper cup seal 730, a fluid passage 735, a fluid passage 740, a support member 745, a body of lubricant
25 750, an overshot connection 755, another support member 760, and a stabilizer 765.

The expandable mandrel 705 is coupled to and supported by the support member 745. The expandable mandrel 705 is further coupled to the expandable mandrel container 710. The expandable mandrel 705 is preferably adapted to
30 controllably expand in a radial direction. The expandable mandrel 705 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred

embodiment, the expandable mandrel 705 comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

5 The expandable mandrel container 710 is coupled to and supported by the support member 745. The expandable mandrel container 710 is further coupled to the expandable mandrel 705. The expandable mandrel container 710 may be constructed from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods, stainless steel, titanium or
10 high strength steels. In a preferred embodiment, the expandable mandrel container 710 is fabricated from material having a greater strength than the material from which the tubular member 715 is fabricated. In this manner, the container 710 can be fabricated from a tubular material having a thinner wall thickness than the tubular member 210. This permits the container 710 to pass
15 through tight clearances thereby facilitating its placement within the wellbore.

In a preferred embodiment, once the expansion process begins, and the thicker, lower strength material of the tubular member 715 is expanded, the outside diameter of the tubular member 715 is greater than the outside diameter of the container 710.

20 The tubular member 715 is coupled to and supported by the expandable mandrel 705. The tubular member 715 is preferably expanded in the radial direction and extruded off of the expandable mandrel 705 substantially as described above with reference to Figs. 1-6. The tubular member 715 may be fabricated from any number of materials such as, for example, Oilfield Country
25 Tubular Goods (OCTG), automotive grade steel or plastics. In a preferred embodiment, the tubular member 715 is fabricated from OCTG.

In a preferred embodiment, the tubular member 715 has a substantially annular cross-section. In a particularly preferred embodiment, the tubular member 715 has a substantially circular annular cross-section.

30 The tubular member 715 preferably includes an upper section 805, an intermediate section 810, and a lower section 815. The upper section 805 of the tubular member 715 preferably is defined by the region beginning in the vicinity

of the mandrel container 710 and ending with the top section 820 of the tubular member 715. The intermediate section 810 of the tubular member 715 is preferably defined by the region beginning in the vicinity of the top of the mandrel container 710 and ending with the region in the vicinity of the mandrel 705. The
5 lower section of the tubular member 715 is preferably defined by the region beginning in the vicinity of the mandrel 705 and ending at the bottom 825 of the tubular member 715.

In a preferred embodiment, the wall thickness of the upper section 805 of the tubular member 715 is greater than the wall thicknesses of the intermediate
10 and lower sections 810 and 815 of the tubular member 715 in order to optimally facilitate the initiation of the extrusion process and optimally permit the apparatus 700 to be positioned in locations in the wellbore having tight clearances.

The outer diameter and wall thickness of the upper section 805 of the tubular member 715 may range, for example, from about 1.05 to 48 inches and 1/8
15 to 2 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the upper section 805 of the tubular member 715 range from about 3.5 to 16 inches and 3/8 to 1.5 inches, respectively.

The outer diameter and wall thickness of the intermediate section 810 of the tubular member 715 may range, for example, from about 2.5 to 50 inches and 1/16
20 to 1.5 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the intermediate section 810 of the tubular member 715 range from about 3.5 to 19 inches and 1/8 to 1.25 inches, respectively.

The outer diameter and wall thickness of the lower section 815 of the tubular member 715 may range, for example, from about 2.5 to 50 inches and 1/16
25 to 1.25 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the lower section 810 of the tubular member 715 range from about 3.5 to 19 inches and 1/8 to 1.25 inches, respectively. In a particularly preferred embodiment, the wall thickness of the lower section 815 of the tubular member 715 is further increased to increase the strength of the shoe 720 when
30 drillable materials such as, for example, aluminum are used.

The tubular member 715 preferably comprises a solid tubular member. In a preferred embodiment, the end portion 820 of the tubular member 715 is slotted,

perforated, or otherwise modified to catch or slow down the mandrel 705 when it completes the extrusion of tubular member 715. In a preferred embodiment, the length of the tubular member 715 is limited to minimize the possibility of buckling. For typical tubular member 715 materials, the length of the tubular member 715 is preferably limited to between about 40 to 20,000 feet in length.

The shoe 720 is coupled to the expandable mandrel 705 and the tubular member 715. The shoe 720 includes the fluid passage 740. In a preferred embodiment, the shoe 720 further includes an inlet passage 830, and one or more jet ports 835. In a particularly preferred embodiment, the cross-sectional shape of the inlet passage 830 is adapted to receive a latch-down dart, or other similar elements, for blocking the inlet passage 830. The interior of the shoe 720 preferably includes a body of solid material 840 for increasing the strength of the shoe 720. In a particularly preferred embodiment, the body of solid material 840 comprises aluminum.

The shoe 720 may comprise any number of conventional commercially available shoes such as, for example, Super Seal II Down-Jet float shoe, or guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 720 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimize guiding the tubular member 715 in the wellbore, optimize the seal between the tubular member 715 and an existing wellbore casing, and to optimally facilitate the removal of the shoe 720 by drilling it out after completion of the extrusion process.

The lower cup seal 725 is coupled to and supported by the support member 745. The lower cup seal 725 prevents foreign materials from entering the interior region of the tubular member 715 above the expandable mandrel 705. The lower cup seal 725 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 725 comprises a SIP cup, available from

Halliburton Energy Services in Dallas, TX in order to optimally provide a debris barrier and hold a body of lubricant.

The upper cup seal 730 is coupled to and supported by the support member 760. The upper cup seal 730 prevents foreign materials from entering the interior region of the tubular member 715. The upper cup seal 730 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cup modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the upper cup seal 730 comprises a SIP cup available from Halliburton Energy Services in Dallas, TX in order to optimally provide a debris barrier and contain a body of lubricant.

The fluid passage 735 permits fluidic materials to be transported to and from the interior region of the tubular member 715 below the expandable mandrel 705. The fluid passage 735 is fluidically coupled to the fluid passage 740. The fluid passage 735 is preferably coupled to and positioned within the support member 760, the support member 745, the mandrel container 710, and the expandable mandrel 705. The fluid passage 735 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 705. The fluid passage 735 is preferably positioned along a centerline of the apparatus 700. The fluid passage 735 is preferably selected to transport materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 40 to 3,000 gallons/minute and 500 to 9,000 psi in order to optimally provide sufficient operating pressures to extrude the tubular member 715 off of the expandable mandrel 705.

As described above with reference to Figs. 1-6, during placement of the apparatus 700 within a new section of a wellbore, fluidic materials forced up the fluid passage 735 can be released into the wellbore above the tubular member 715. In a preferred embodiment, the apparatus 700 further includes a pressure release passage that is coupled to and positioned within the support member 260. The pressure release passage is further fluidically coupled to the fluid passage 735. The pressure release passage preferably includes a control valve for controllably opening and closing the fluid passage. In a preferred embodiment, the control valve is pressure activated in order to controllably minimize surge pressures. The pressure release passage is preferably positioned substantially orthogonal to the

centerline of the apparatus 700. The pressure release passage is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 500 gallons/minute and 0 to 1,000 psi in order to reduce the drag on the apparatus 700 during insertion into a new section of a wellbore and to minimize surge pressures on the new wellbore section.

The fluid passage 740 permits fluidic materials to be transported to and from the region exterior to the tubular member 715. The fluid passage 740 is preferably coupled to and positioned within the shoe 720 in fluidic communication with the interior region of the tubular member 715 below the expandable mandrel 705. The fluid passage 740 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in the inlet 830 of the fluid passage 740 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 715 below the expandable mandrel 705 can be optimally fluidically isolated from the region exterior to the tubular member 715. This permits the interior region of the tubular member 715 below the expandable mandrel 205 to be pressurized.

The fluid passage 740 is preferably positioned substantially along the centerline of the apparatus 700. The fluid passage 740 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill an annular region between the tubular member 715 and a new section of a wellbore with fluidic materials. In a preferred embodiment, the fluid passage 740 includes an inlet passage 830 having a geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

In a preferred embodiment, the apparatus 700 further includes one or more seals 845 coupled to and supported by the end portion 820 of the tubular member 715. The seals 845 are further positioned on an outer surface of the end portion 820 of the tubular member 715. The seals 845 permit the overlapping joint between an end portion of preexisting casing and the end portion 820 of the tubular member 715 to be fluidically sealed. The seals 845 may comprise any

number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 845 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in
5 Dallas, TX in order to optimally provide a hydraulic seal and a load bearing interference fit in the overlapping joint between the tubular member 715 and an existing casing with optimal load bearing capacity to support the tubular member 715.

In a preferred embodiment, the seals 845 are selected to provide a sufficient
10 frictional force to support the expanded tubular member 715 from the existing casing. In a preferred embodiment, the frictional force provided by the seals 845 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 715.

The support member 745 is preferably coupled to the expandable mandrel
15 705 and the overshot connection 755. The support member 745 preferably comprises an annular member having sufficient strength to carry the apparatus 700 into a new section of a wellbore. The support member 745 may comprise any number of conventional commercially available support members such as, for example, steel drill pipe, coiled tubing or other high strength tubular modified in
20 accordance with the teachings of the present disclosure. In a preferred embodiment, the support member 745 comprises conventional drill pipe available from various steel mills in the United States.

In a preferred embodiment, a body of lubricant 750 is provided in the annular region above the expandable mandrel container 710 within the interior of
25 the tubular member 715. In this manner, the extrusion of the tubular member 715 off of the expandable mandrel 705 is facilitated. The lubricant 750 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants, or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 750 comprises
30 Climax 1500 Antisieze (3100) available from Halliburton Energy Services in Houston, TX in order to optimally provide lubrication to facilitate the extrusion process.

The overshot connection 755 is coupled to the support member 745 and the support member 760. The overshot connection 755 preferably permits the support member 745 to be removably coupled to the support member 760. The overshot connection 755 may comprise any number of conventional commercially available
5 overshot connections such as, for example, Innerstring Sealing Adapter, Innerstring Flat-Face Sealing Adapter or EZ Drill Setting Tool Stinger. In a preferred embodiment, the overshot connection 755 comprises a Innerstring Adapter with an Upper Guide available from Halliburton Energy Services in Dallas, TX.

10 The support member 760 is preferably coupled to the overshot connection 755 and a surface support structure (not illustrated). The support member 760 preferably comprises an annular member having sufficient strength to carry the apparatus 700 into a new section of a wellbore. The support member 760 may comprise any number of conventional commercially available support members
15 such as, for example, steel drill pipe, coiled tubing or other high strength tubulars modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the support member 760 comprises a conventional drill pipe available from steel mills in the United States.

The stabilizer 765 is preferably coupled to the support member 760. The
20 stabilizer 765 also preferably stabilizes the components of the apparatus 700 within the tubular member 715. The stabilizer 765 preferably comprises a spherical member having an outside diameter that is about 80 to 99% of the interior diameter of the tubular member 715 in order to optimally minimize buckling of the tubular member 715. The stabilizer 765 may comprise any number
25 of conventional commercially available stabilizers such as, for example, EZ Drill Star Guides, packer shoes or drag blocks modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the stabilizer 765 comprises a sealing adapter upper guide available from Halliburton Energy Services in Dallas, TX.

30 In a preferred embodiment, the support members 745 and 760 are thoroughly cleaned prior to assembly to the remaining portions of the apparatus 700. In this manner, the introduction of foreign material into the apparatus 700